UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Suedeen G. Kelly, Philip D. Moeller,
and Jon Wellinghoff.

San Diego Gas and Electric Company, Complainant	Docket Nos. EL00-95-173, 174, 175, 176, and 177
v.	
Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange Corporation, Respondents.	
Investigation of Practices of the California Independent System Operator Corporation and the California Power Exchange	Docket Nos. EL00-98-159, 160, 161, 162, and 163

ORDER ON COMPLIANCE FILINGS

(Issued November 2, 2006)

1. In this order, the Commission acts on compliance filings made by certain sellers as required by a January 26, 2006 Order on cost offset demonstrations,[1] which will allow the California Independent System Operator Corporation (CAISO) to begin calculating refunds for California ratepayers.

2. As discussed below, we accept in whole or in part the compliance filings of Avista Energy, Inc. (Avista), Portland General Electric Company (Portland General) and Powerex Corp. (Powerex) and reject the compliance filings of Sempra Energy Trading Corp. (Sempra) and TransAlta Energy Marketing (U.S.) Inc. (TransAlta). We find that, unless otherwise noted, the sellers have satisfactorily complied with the January 26 Order. Those sellers that have complied must now submit their final cost offset determinations as adjusted herein to the CAISO so that it may begin its refund calculations.

[1] *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Serv.*, 114 FERC ¶ 61,070 (2006) (January 26 Order), *reh'g pending*.

3. In making these determinations, the Commission has striven to achieve a reasonable balance between sellers' opportunity to demonstrate their costs, the parties' right to challenge refund liability offsets, and prompt resolution of the California refund proceeding. In making these determinations, the Commission is meeting its statutory obligation to ensure that the mitigated market clearing price (MMCP) does not result in a confiscatory rate for any individual seller.

Background

4. As noted previously, the purpose of the cost filing process has been to allow an individual seller the opportunity to demonstrate that, after application of the MMCP, its costs of providing electricity to the CAISO/California Power Exchange (PX) markets exceed the total revenues it received from those markets during the Refund Period (October 2, 2000 through June 20, 2001).[2] Marketers and those reselling purchased power have been aware that they would be afforded this opportunity at the end of the refund hearing since at least December 2001,[3] and generators since May 15, 2002.[4]

5. The Commission's primary concern throughout the refund proceeding has been to remedy rates that buyers may have paid above the zone of reasonableness, which led the Commission to establish the MMCP.[5] Nevertheless, the Commission has balanced this key objective with its concomitant statutory obligation to ensure that the MMCP does not result in a confiscatory rate for any individual seller. The MMCP, which was designed to emulate a competitive market price[6] during the Refund Period, does not take into account a seller's actual individual costs of providing electricity to those markets, but rather

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[2] *Id.* at P 3.

[3] *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Serv.*, 97 FERC ¶ 61,275, at 62,193-94 (2001) (December 19 Order).

[4] *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Serv.*, 99 FERC ¶ 61,160, at 61,656 (2002) (May 15 Order).

[5] *See San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Serv.*, 105 FERC ¶ 61,065, at P 17 (2003) (*citing* May 15 Order, 99 FERC ¶ 61,160 at 61,655 and n.6).

[6] The MMCP is based upon the marginal cost of the last unit dispatched to meet load in the ISO's real-time market, and equals the sum of: (1) the product of the maximum heat rate of any unit dispatched and the gas price; (2) a $6/MWh operation and maintenance adder; and (3) a ten percent credit-worthiness adder. *See generally San Diego Gas & Elec. Co. v. Sellers of Energy & Ancillary Services*, 96 FERC ¶ 61,120, at 61,517 – 61,519 (2001).

reflects an imputed level of costs. Consequently, in the order issued on December 19, 2001, the Commission announced its intention to provide an opportunity after the conclusion of the refund hearing for marketers to submit cost evidence on the impact of the refund methodology on their overall revenues over the Refund Period.[7] The Commission stated that, to consider any adjustment, marketers would have to demonstrate that the refund methodology results in a total revenue shortfall for all jurisdictional transactions during the Refund Period.[8] The Commission stated that it would consider these cost filing submissions "in light of the regulatory principle that sellers are guaranteed only an opportunity to make a profit."[9] The Commission has consistently stated that all claimed costs must be fully supported, and that, while sample invoices could suffice, it had to be clear from the filing how the costs were derived; otherwise the costs would be disallowed.[10]

6. On August 8, 2005, the Commission issued an order that established the framework for the evidence sellers were required to submit if they wished to demonstrate that the refund methodology would result in an overall revenue shortfall for their transactions in the CAISO and the PX markets during the Refund Period.[11] Finally, per the August 8 Order and August 25 Technical Conference, the Cost Filing Template informed sellers that unsupported entries may be subject to rejection for lack of support.[12]

7. On August 25, 2005, pursuant to the Commission's directive,[13] Commission staff convened a technical conference to develop a uniform format to be used by the sellers when making their cost filings and provide guidance on the preparation of the cost filings. At the end of the technical conference, Commission staff directed sellers to use a

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[7] December 19 Order, 97 FERC ¶ 61,275 at 62,193-94 and 62,254.

[8] *Id.*

[9] *Id.*

[10] *See Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Serv.*, 112 FERC ¶ 61,176, at P 103 (2005) (August 8 Order); *see also* January 26 Order, 114 FERC ¶ 61,070 at P 13 ("per the August 8 Order and August 25 Technical Conference, the Cost Filing Template informed sellers that unsupported entries may be subject to rejection for lack of support.")

[11] August 8 Order, 112 FERC ¶ 61,176 at P 1.

[12] *Id.*

[13] *Id*. at P 116.

modified version of the uniform template submitted by the California Parties.[14] On August 26, 2005 the Commission extended the cost filing deadline to September 14, 2005 to give filers additional time to take into account the guidance provided by Commission staff at the technical conference. Several parties submitted cost filings on September 14, 2005.[15]

8. On January 26, 2006, the Commission determined which sellers had demonstrated that the refund methodology would result in an overall revenue shortfall for their transactions in the relevant California markets during the Refund Period.[16] Of the many cost filings submitted, the Commission accepted, subject to conditions and/or modifications, the filings of Avista, Portland General, Powerex, Sempra and TransAlta (collectively, Sellers) and required them to make compliance filings. On February 10, 2006, the Sellers made their respective compliance filings.[17]

Notice of Filings and Pleadings

9. Notices of the compliance filings were published in the *Federal Register*, 71 Fed. Reg. 11,602 and 71 Fed. Reg. 11,604 (2006), with protests and interventions due on or before March 13, 2006. The California Parties filed motions to reject and protests to the compliance filings. Portland General, Powerex, Sempra, TransAlta and the California Parties filed answers. The California Parties also filed a motion to lodge evidence regarding Powerex's costs.

Discussion

A. Procedural Matters

10. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2006), prohibits an answer to a protest and/or answer unless otherwise

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[14] The California Parties are the People of the State of California *ex rel.* Bill Lockyer, Attorney General; the California Electricity Oversight Board; the Public Utilities Commission of the State of California; Pacific Gas and Electric Company; and Southern California Edison Company.

[15] *See* January 26 Order, 114 FERC ¶ 61,070 at P 16.

[16] January 26 Order, 114 FERC ¶ 61,070.

[17] Portland General and Powerex subsequently filed errata to correct errors that were made in their filings.

ordered by the decisional authority. We will accept the answers filed in these proceedings because they have provided information that assisted us in our decision-making process.[18]

B. Substantive Matters

11. As explained below, in this order, we accept Avista's compliance filing, conditionally accept Portland General's and Powerex's compliance filings, subject to modification, and reject Sempra's and TransAlta's compliance filings and proposed cost offsets. We direct Avista, Portland General and Powerex to submit their final cost offsets, incorporating the directives discussed herein, to the CAISO within 15 days of the date of this order.

1. Avista

12. In the January 26 Order, the Commission accepted Avista's cost filing subject to the following modifications: (1) removal of congestion revenues and congestion costs from its cost data;[19] (2) removal of the PX's wind-up charges;[20] (3) recalculation of all purchase power costs associated with matched sales into the CAISO;[21] and (4) validation of revenues from matched sales against the CAISO settlement data.[22]

13. Avista claims that its compliance filing correctly implements the Commission's directives. The California Parties request that the Commission reject the filing or, alternatively, direct Avista to make a further compliance filing because they assert that the Commission-accepted cost filing and supplemental cost filing have numerous errors and omissions. For specifics, they refer the Commission to the arguments set forth in pleadings submitted prior to the issuance of the January 26 Order and their request for

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[18] Since the California Parties are already a party to Docket Nos. EL00-95-000 and EL00-98-000, they did not need to file a separate motion to intervene in these sub-dockets to maintain their party status.

[19] *Id*. at P 104.

[20] *Id*. at P 179.

[21] *Id*. at P 175.

[22] *Id*. at App. B. With respect to the remainder of the settlement data identified in Appendix B, we note that the Commission directed Avista to file the revised cost inputs with the Commission within 15 days of the January 26 Order and to reflect the final settlement data from the Automated Power Exchange, Inc. (APX), CAISO and/or PX in its final report to the CAISO. *See Id*. at P 182.

rehearing of the January 26 Order. Such an incorporation of arguments by reference places the Commission in the untenable position of determining which arguments are still relevant to the compliance filing before us. For this reason, we will not consider the arguments that the California Parties seek to incorporate by reference.

14. We find that, as directed, Avista has excluded congestion costs and revenues from its template, excluded costs associated with the PX wind-up fees, and appropriately corrected the discrepancy with regard to Avista's transactions with Turlock through the recalculation of its matched transaction costs. Furthermore, in accord with the January 26 Order, Avista has appropriately removed the Bonneville transactions from its matched energy cost calculations and corrected the error related to the valuation of those transactions.[23] Since the modifications in Avista's filing comply with the directives of the January 26 Order, we accept Avista's compliance filing.

2. Portland General

15. In the January 26 Order, the Commission accepted Portland General's cost filing subject to certain modifications. The Commission directed Portland General to complete a new stacking analysis of all available resources for its portfolio calculation or production costs because the stacking analysis from the original filing was biased.[24] Specifically, the Commission required Portland General to (1) provide a complete stacking analysis of all its available resources, (2) demonstrate which resources were necessary for native load and other primary obligations and those available for sales to the CAISO and PX markets in each hour, and (3) develop a resulting average portfolio cost for those available resources.[25]

16. The Commission also directed Portland General to make several other revisions: (1) remove short-term purchases made to serve sales into the CAISO and PX;[26] (2) remove uninstructed energy purchase costs;[27] (3) include recirculation transactions;[28]

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[23] *See Id*. at P 178.

[24] *See Id*. at P 252.

[25] *See Id*.

[26] *See Id*. at P 253.

[27] *See Id*. at P 254.

[28] *See Id*.

(4) include sales made pursuant to section 202(c) of the Federal Power Act (FPA);[29] (5) remove costs related to transmission losses;[30] (6) reflect CAISO and/or PX final settlement data for all revenues, including all manual adjustments;[31] and (7) reconcile errors in revenues shown by Commission staff's calculations.[32]

a. Stacking Analysis

17. In response to the Commission's directive that it develop a new stacking analysis incorporating all available resources, Portland General has provided four new distinct stacking analyses (Case 1, 1.1, 2 and 2.1) resulting in four different cost offsets ranging from $20.6 million to $30.4 million. Portland General states that, in order to be responsive to the January 26 Order, it created a new stacking methodology that follows the stacking analysis of the Public Service Company of New Mexico (PNM), which the Commission found satisfactory.[33] Portland General explains that it made several assumptions in its original filing that are not consistent with the PNM model; thus, it broke its compliance filing cost calculations into two cases: the first case uses the PNM methodology (Case 1), and the second case incorporates Portland General's original assumptions (Case 2). In preparing its compliance filing, Portland General states that it discovered two errors in the coding of the data in its original filing.[34] Portland General states that it has corrected these errors in Case 1.1 and Case 2.1.

18. The California Parties contend that the four new stacking analyses fall short of the requirements that the Commission imposed and should be rejected. The California Parties claim that Portland General's creation of four new stacking analyses represents an attempt to take a second bite at the apple. The California Parties argue that, by changing the assumptions underlying its original cost filing and/or correcting "so-called" errors, Portland General has managed to increase its cost filing offset. The California Parties

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[29] *See Id*. at P 255.

[30] *See Id*.

[31] *See Id*. at App. B.

[32] *See Id*.

[33] *See Id*. at n.225.

[34] Portland General discovered two errors: (1) two purchases in the merchant portfolio had not been properly coded for removal and (2) a number of sales were erroneously coded as spot transactions unassociated with deliveries of energy from Portland General's Boardman coal plant. Exh. PGE-20, Stathis Testimony at 11:9-13:11 (Stathis Testimony).

point out deficiencies and errors in the analyses: (1) the exclusion of merchant and booked-out transactions in its Case 2 stacking analyses that should have been included because Portland General failed to prove that these transactions were unavailable for sale into the CAISO/PX markets, (2) possible failure to excluded primary obligations from the analyses, (3) failure to remove certain opportunity purchases, for example, balance of the week (BOW) and balance of the month (BOM) transactions, from the set of purchases used to calculate its average portfolio costs,[35] (4) possible incorrect manner of applying to CAISO and PX sales the average cost of the purchases remaining in the portfolio after opportunity purchases had been removed,[36] and (5) failure to match purchase and sales volumes for certain categories of transaction. The California Parties also contend that Portland General has failed to provide sufficient documentation to support the methodologies employed in its stacking analyses.

19. Portland General responds that, in order to be responsive to the Commission's directive in the January 26 Order, it had to change the underlying assumptions in its original filing. Portland General asserts that the fact that its cost offset rose as a result of implementing the Commission's directives does not mean that the stacking process was skewed. Portland General claims that instead the results of the PNM stacking methodology confirm that its original filing was understated. Portland General states that this claim is validated by the fact that, when it adjusted the PNM methodology to include the same conservative assumptions it made in its original filing, its average portfolio cost was consistent with its original filing.

20. Portland General addresses the exclusion of merchant and booked-out transactions in its Case 2 analysis by pointing out that it had treated these categories as unavailable to serve CAISO/PX sales in its original filing. Portland General argues that, because the Commission did not direct it to include these transactions in its compliance filing, it was inappropriate to do so. Portland General adds that the California Parties failed to object to the exclusion of these transactions from its original filing.

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[35] They criticize, among other things, Portland General's inclusion of three purchases referred to as the "BP Deals" because the transactions in question were one month in length. These transactions included, for example, a 25 MW on-peak purchase from BP Energy at $100.50/MWh and a 25 MW off-peak purchase from BP Energy at $92.00/MWh. The California Parties claim that Portland General included the BP Deals in its average cost calculations because they were recorded in its merchant trade book and Portland General included all transactions from the merchant trade book regardless of duration.

[36] This issue is addressed in the section below that discusses Portland General's removal of short-term purchases made to serve sales into the CAISO and PX. *See infra* P 26-30.

21. Portland General also contends that the California Parties' argument regarding the treatment of primary obligations in the stacking analysis go beyond the scope of the compliance filing because the argument is based upon a new argument in the California Parties' pending request for rehearing of the January 26 Order that only native load, and not primary obligations, should be allocated least-cost resources during a load serving entity's (LSE) assignment of resources. Portland General notes that, in the January 26 Order, the Commission found that the PNM stacking analysis, which allocated least-cost resources to native load and primary obligations, appropriately implemented the portfolio cost methodology required for LSEs.[37]

22. Portland General argues that California Parties are confusing the issues regarding its inclusion of the three "BP Deals" and BOM and BOW transactions. Portland General contends that it did not remove the three BP deals from its Case 1 and Case 2 analyses because the Commission did not direct it to do so. However, Portland General explains that it did remove the three BP deals from Case 1.1 and Case 2.1 in the event that the Commission deemed it appropriate. Portland General responds to the California Parties' claim that there was "no objective proof" that BOW and BOM purchases were for anticipated native-load by noting that the Commission found it appropriate for Portland General to include them.

23. Portland General disagrees with the California Parties' claims that the presence of an imbalance between purchase and sales volumes indicates that the stacking methodology is biased. Portland General contends that this imbalance is simply a result of excluding several categories of transactions that were unrelated to serving the CAISO/PX markets from its resource stack. Portland General states that the California Parties failed to object to the exclusion of these transactions in the original filing, thus waiving their right to raise the issue here. Portland General adds that the Commission did not direct it to alter the treatment of these purchases, and, therefore, it has continued to exclude them from the compliance filing. Portland General defends its creation of the Net System Purchase category that it used to allocate a volume of purchases equal to the imbalance in volumes. Portland General explains that, in order to bring its portfolios back into balance, it priced a related volume of resources at zero before placing them into the supply stack.

24. Finally, Portland General claims that the California Parties' demand for additional documentation is a collateral attack on the August 8 Order and January 26 Order. Portland General notes that, in the August 8 Order, the Commission did not require sellers to provide data on their entire portfolio to adequately determine the costs to serve CAISO/PX sales or direct additional discovery to verify the costs and revenues claimed

[37] *Citing* January 26 Order, 114 FERC ¶ 61,070 at P 252, n.225.

by Portland General and other sellers.[38] Portland General adds that, in the January 26 Order, the Commission found that Portland General had adequately justified the cost of resources used to serve CAISO/PX sales, even though Portland General had not provided documentation for transactions unrelated to the CAISO/PX sales.[39] Portland General states that the underlying documentation for the transactions in the compliance filing is the same as that provided in its original filing, except for the inclusion of a 20-year power purchase agreement with Trans-Energy-Oregon, Inc. in the compliance filing that it has included to respond to the Commission's directive to include all resources in its stacking analysis.

25. We disagree that Portland General's submittal represents a second "bite at the apple." Contrary to California Parties' contentions, we find that Portland General's Case 2 analysis provides the stacking analysis that appropriately includes all owned and purchased resources, consistent with the directives of the January 26 Order.[40] In the Case 2 analysis, Portland General has sorted, or stacked, each resource used in each hour of each day of the Refund Period. As a result, Commission staff has been able to verify the resource costs used by Portland General to develop its hourly average portfolio. We find that, through the Case 2 analysis, Portland General has properly demonstrated its average costs for making sales to the CAISO/PX. Also, contrary to California Parties' assertion, in the January 26 Order, the Commission found that book-out transactions were not available for resale into the ISO/PX markets, and therefore it was reasonable to exclude them from the cost demonstrations.[41] Accordingly, we conditionally accept the Case 2 analysis, subject to the modifications directed below. We note that, in the Case 1, Case 1.1 and Case 2.1 analyses, Portland General has removed assumptions that it used in its original filing. Because the Commission did not direct Portland General to remove those assumptions when providing its new stacking analysis, we find that those analyses are not responsive to the Commission's directive in the January 26 Order. Accordingly, we reject the Case 1, Case 1.1 and Case 2.1 analyses.

b. Removal of Short-Term Purchases Made to Serve Sales into the CAISO and PX

26. In order to remove short-term purchases, Portland General has excluded the cost of these purchases to the extent they were not available for resale into the CAISO and PX markets.

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[38] *Citing Id*. at P 31-40.

[39] *Citing Id*. at P 250.

[40] *Id.* at P 252.

[41] *See Id*. at P 235.

27. The California Parties argue that Portland General employed a biased method for excluding short-term opportunity purchases from its average portfolio costs.[42] They contend that Portland General's methodology calculates the average cost based on resources that remain in the purchase portfolio after opportunity purchases have been removed, regardless of the number of MWhs remaining in the portfolio.[43] The California Parties believe that this methodology is not correct because it creates a situation where one single MWh of high priced electricity can set the average for an entire hour. The California Parties recommend an alternative revenue neutral methodology that would not attribute any profits or losses to volumes of CAISO/PX sales that exceed the volume of purchases in the purchases portfolio.[44]

28. Portland General responds that it was proper to use its average portfolio cost to serve sales when the volume of purchases was smaller than the volume of sales into the CAISO/PX markets. Portland General argues that the Commission directed it to use its average portfolio cost when it rejected Portland General's argument that it should include short term purchases for resale to the ISO and PX because otherwise it would not have had sufficient supplies to serve sales it actually made.[45] Portland General claims that its use of its average portfolio cost is a logical way to resolve the problem created by excluding these short-term purchases.

29. Portland General contends that the analysis of the California Parties' witness deliberately leaves Portland General's resource and sales stacks out of balance so that there can be more hours in which Portland General is left with no resources to serve CAISO/PX sales in the stacking analysis.[46] Portland General asserts that the method it has used generally decreases Portland General's average portfolio costs because valuing Net System Purchases at zero places them at the bottom of the resource stack, thus pushing lower-cost purchases higher up in the stack prior to allocation.[47]

30. In the January 26 Order, the Commission found that Portland General had sufficiently demonstrated that it was appropriate to include short-term energy purchases

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[42] Exh. CAP-Portland No. 11, Berry Testimony at 15:10-13 (Berry Testimony).

[43] *Id*. at 14:26-15:8.

[44] *Id*. at 15:24-27.

[45] *Citing* January 26 Order, 114 FERC ¶ 61,070 at P 253.

[46] *See* Stathis Testimony at 14:18-20.

[47] *Id*. at 14:11-14.

in its average portfolio calculations for December 2000 because of extenuating circumstances.[48] However, for all other instances, the Commission found that Portland General could not include short-term purchases because they were disallowed opportunity purchases, and the Commission required Portland General to remove them from its analysis. Portland General has not excluded these short-term opportunity purchases from its Case 2 analysis. As a result, we agree with the California Parties and direct Portland General to exclude all short-term purchases, other than the purchases of December 2000, from the Case 2 analysis to arrive at the cost offset.[49]

c. Exclusions of Uninstructed Energy Purchase Costs and Inclusion of Recirculation Transactions

31. In order to remove uninstructed energy purchases, Portland General has excluded the cost of these purchases not available for resale into the CAISO and PX markets. Portland General notes that it did not change its methodology in response to the Commission's instruction to include revenues associated with recirculation transactions. Portland General explains that, in its original filing, it matched these transactions by using internal scheduling data to identify CAISO purchases and sales where the price differential equaled the recirculation fee being charged at that time. Portland General states that, because the Commission was unclear as to whether it is appropriate to treat these transactions as matched, Portland General chose to maintain its methodology from its original filing. Portland General explains that it then identified the margin on each purchase and sale match and applied that margin to offset Portland General's costs of serving the CAISO/PX sales.

32. The California Parties claim that, contrary to the Commission's directive, Portland General has included uninstructed energy purchases in its compliance filing. The California Parties argue that Portland General erroneously included recirculation transactions categorized as uninstructed energy purchases in direct contradiction to the directives of the January 26 Order.

33. Portland General argues that the January 26 Order was unclear on this issue. Portland General contends that the Commission's directives for it to both include recirculation transactions and exclude uninstructed energy purchase costs are contradictory. Portland General states that, in its original filing, it had matched recirculation sales and purchases. It states that some of these sales and purchases were from uninstructed energy. Because the Commission did not direct Portland General in the January 26 Order to treat the recirculation transactions as unmatched, Portland

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[48] January 26 Order, 114 FERC ¶ 61,070 at P 253.

[49] These opportunity purchases include the BP Deals identified earlier. *See supra* P 18 n.35, P 22.

General states that it would have been non-compliant to do so. Portland General believes that it does not have discretion to change its original methodology until the Commission rules on the request for clarification of the January 26 Order on this issue.

34. We find that Portland General has properly excluded the recirculation transactions from the calculation of its average portfolio. In the January 26 Order, the Commission noted that Portland General had committed to separately include the net revenues from the recirculation transactions in its cost filing because it could match those transactions; therefore, the Commission directed Portland General to submit in its compliance filing the recirculation transactions separately from its average portfolio calculations.[50] Portland General has done so here by now separately stating the recirculation transactions from the average portfolio calculations.

35. However, Portland General continues to include in the matched recirculation transactions the amounts of those transactions settled as uninstructed energy purchases. Consistent with the January 26 Order,[51] we find that Portland General cannot resell uninstructed energy to the market. Accordingly, we direct Portland General to remove uninstructed energy costs related to its matched recirculation transactions from its analysis. We note, however, that, consistent with the January 26 Order, uninstructed energy revenues must remain in the cost recovery analysis.

d. Congestion Costs

36. In the January 26 Order, the Commission noted that Portland General, in its reply comments, erroneously included congestion costs and committed to removing them from its cost recovery filing.[52] In its compliance filing, Portland General continues to include congestion costs.

37. The California Parties argue that the inclusion of congestion costs is contrary to the Commission's directive in the January 26 Order.

38. We agree with the California Parties that the congestion costs in Portland General's template should be rejected. Notwithstanding the fact that Portland General previously claimed that the inclusion of congestion costs in its template was an error, it has not removed these costs from its compliance filing. In the January 26 Order, the Commission directed all sellers to remove congestion revenues or congestion costs as a

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[50] January 26 Order, 114 FERC ¶ 61,070 at P 254, n. 226.

[51] *Id.* at P 107-108.

[52] *Id.* at n.221.

component of their cost filings.[53] Accordingly, we direct Portland General to remove these congestion costs.

e. Inclusion of FPA Section 202(c) Sales and Removal of Transmission Losses Costs

39. In order to include revenues associated with FPA section 202(c) sales, as directed, Portland General states that it has used the average cost of its supply portfolio to calculate the cost of serving FPA section 202(c) sales. Regarding the disputed revenue figure, Portland General agrees that there may be a discrepancy with that figure depending on which CAISO data was used. Portland General states that it incorporated the "final" revenue data in its compliance filing but that even the "final" number may be incorrect with regard to Portland General's FPA section 202(c) sales.

40. The California Parties contend that Portland General has inappropriately used new cost data to compute an average hourly portfolio cost for 251 of the 265 hours that it sold energy pursuant to FPA section 202(c). The California Parties contend that Portland General's cost offset would be reduced by millions of dollars if this new cost data is disallowed.[54] The California Parties also claim that the CAISO has provided Portland General finalized revenue data and therefore the Commission should require Portland General to adjust its cost claim to reflect the correct estimate of its section 202(c) revenues.

41. Portland General responds that it has provided the new cost data to supplement Portland General's cost claim in response to the directive in the January 26 Order. Portland General argues that it was proper to include this new data in its compliance filing in response to the methodology required by the January 26 Order for valuing the additional hours in question.[55] Portland General adds that it has included final cost revenue data in its filing to the CAISO but that the final revenue number it received is incorrect with respect to its section 202(c) sales.

42. We find that Portland General has included the costs and revenues related to FPA section 202(c) transactions, as directed. Contrary to the California Parties' arguments, we find that it was appropriate for Portland General to provide the cost data necessary to implement the methodology for calculating the costs associated with section 202(c)

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[53] *Id*. at P 104.

[54] Berry Testimony at 22:1-5.

[55] *Citing* January 26 Order, 114 FERC ¶ 61,070 at P 83.

transactions required by the January 26 Order. However, if any discrepancy continues to exist with the CAISO's revenue figures, we direct the Portland General to reconcile any further adjustments to the CAISO's figures.

43. Portland General claims that it has excluded the transmission losses included in its original filing. The California Parties raise no concerns regarding Portland General's exclusion of costs related to transmission losses. We find that Portland General has properly removed costs related to transmission losses from its cost recovery analysis in the compliance filing.

f. Update Revenue Data to Reflect CAISO and/or PX Final Settlement Data for All Revenues, Including All Manual Adjustments and Reconcile Errors in Revenues Shown by Commission Staff's Calculations

44. Portland General states that final CAISO/PX settlement data was not available to the sellers when the cost recovery calculations were made and, as a result, it relied on preparatory rerun data provided by the CAISO and PX to estimate its cost recovery offset.[56] Portland General acknowledges the Commission's directive in the January 26 Order to merge and finalize revenue data so that the final set of CAISO/PX data can be incorporated into its cost filing.[57]

45. We recognize that Portland General could not provide finalized revenue data until it received final settlement data from the CAISO and PX. As with all other sellers, we require Portland General to include final revenue data in its final cost offset report to the CAISO. In addition, as previously directed, Portland General must reconcile the errors in revenue noted in the January 26 Order[58] in the final cost offset it will submit to the CAISO.

3. Powerex

46. In the January 26 Order, the Commission accepted Powerex's cost filing subject to certain modifications. The Commission directed Powerex to: (1) include revenues sales for the entire Refund Period (in particular, those made between January 1, 2001 and January 16, 2001), regardless of transaction size;[59] (2) include affiliate transactions

[56] Stathis Testimony at 2:25-3:3.

[57] *Id*. at 3:3-3:7.

[58] *See* January 26 Order, 114 FERC ¶ 61,070 at App. B.

[59] *Id*. at P 274.

related to British Columbia Hydro and Power Authority (BC Hydro);[60] (3) include multi-day sales;[61] (4) remove uninstructed energy purchase costs;[62] (5) reflect CAISO and/or PX final settlement data for all revenues, including all manual adjustments;[63] and (6) reconcile errors in revenues shown by Commission staff calculations.[64]

a. Inclusion of Revenue Sales for the Entire Refund Period Regardless of Transaction Size

47. In its compliance filing, Powerex provides two alternative revised average cost portfolio calculations. The first alternative calculates an average portfolio cost for the October 2, 2000 through January 16, 2001 time period. Like its original cost filing, the second alternative is limited to the October 2, 2000 to the December 31, 2000 time period. Powerex states that it provides the second alternative as a precaution. Powerex commits that, once the recalculation of the average portfolio cost is finalized upon the receipt of the final settlement data from the CAISO and PX, it will submit to the CAISO its revised cost offset filing incorporating, among other things, all sales for the entire Refund Period, regardless of size, including real-time imbalance charges after December 31, 2000.[65]

48. The California Parties argue that Powerex has not included all of its revenues from all of its sales to the CAISO and PX markets after December 31, 2000, as directed. First, the California Parties contend that Powerex did not include revenues from the January 1-16, 2001 time period, as directed. Second, they claim that Powerex has failed to comply with the January 26 Order because it has submitted cost information and documentation for the January 1-16, 2001 time period that the Commission did not request. Third, the California Parties argue that Powerex has attempted to exclude certain uninstructed energy sales made to the CAISO during the January 17, 2001 to June 20, 2001 time period by rationalizing that these uninstructed energy sales were the result of incidental

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[60] *Id*. at P 276-78.

[61] *Id*. at P 279.

[62] *Id*.

[63] *Id*. at App. B.

[64] *Id*.

[65] *See* Powerex March 14, 2006 Answer at 16; Powerex Attachment 7, Affidavit of David Wong at P 8 (Wong Affidavit).

transactions that "do[] not represent participation in the CAISO's energy markets."[66] Finally, the California Parties claim that Powerex should have provided full and complete recalculations incorporating revenues from the post-December 31, 2000 sales.

49. Powerex points out that the Commission did not direct Powerex to include the revenues after December 31, 2000 in its compliance filing but instead directed it to include that information, including revenues associated with the real-time imbalance energy charges, in its cost filing with the CAISO.[67] With respect to the uninstructed energy revenues, Powerex responds that, although it did not participate in the CAISO energy markets after January 16, 2001, it was subject to real-time imbalance energy charges as a condition of obtaining transmission service from the CAISO. Powerex states that these charges were an inescapable result of using the CAISO transmission and necessarily led to charges for positive and negative uninstructed energy due to deviation from schedules or charges for losses. Powerex adds that the California Parties have grossly distorted Powerex's actual CAISO transactions between January 17, 2001 and June 20, 2001.[68]

50. We find acceptable that Powerex include in its average cost portfolio the non-affiliate purchase costs that it incurred from January 1-16, 2001. Thus, we find that Powerex's second alternative calculations are in compliance with the January 26 Order and reject the demonstrations for the period from October 2, 2000 to December 31, 2000. As Powerex points out, because the Commission is requiring Powerex to include the revenues it received after December 2000, it is reasonable to include the associated purchase costs as well. We find that Powerex has met the burden set forth in the August 8 Order by providing invoices that verify its purchase costs. Accordingly, we accept the revised purchase costs. Furthermore, the Commission accepts Powerex's commitment to include any revenues associated with real-time imbalance charges in its final cost filing with the CAISO. Since the deadline for the CAISO to submit its final settlement figures to market participants has passed, Powerex has at its disposal the necessary data to complete the calculation of its cost offset. We direct Powerex to utilize the CAISO final settlement data to complete the calculations required, as directed in the January 26 Order.[69]

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[66] *Quoting Id*. at P 10, n.1.

[67] Powerex notes that it has committed to including all CAISO and PX revenue for the entire Refund Period in its final cost offset filing with the CAISO. *Citing Id*. at P 8.

[68] On March 13, 2006, the day before Powerex filed its answer, the California Parties filed supplemental testimony to update and correct calculations. Powerex claims that, while some errors in the testimony have been corrected, other significant errors remain.

[69] *See* January 26 Order, 114 FERC ¶ 61,070 at P 56, App. B and App. E.

b. Inclusion of Affiliate Transactions Related to BC Hydro

51. In the January 26 Order, in order to determine the quantity of affiliate purchases Powerex made, the Commission directed Powerex to include in its average cost portfolio BC Hydro's excess power above native load, as reported to the British Columbia Utility Commission (BCUC).[70] The Commission stated that the costs that Powerex could recover with respect to affiliate transactions would be limited to BC Hydro's rate on file with the BCUC at the time that the transactions occurred.[71]

(1) Netting

52. Powerex states that, while it does not explicitly report generation levels and native load to the BCUC, it does files quarterly reports on its own trade sales and purchases, which yield the same information. Powerex further states that it has netted its sales and purchases for its entire portfolio of third-party purchases over the entire October 2, 2000 to January 16, 2001 time period. Powerex contends that the net amount of those transactions represents the quantity of power BC Hydro produced above its native load obligation (exports), which equals that amount of its affiliate purchases. Powerex explains that, when it had insufficient third-party purchases to service its sales obligations, BC Hydro generated, on Powerex's behalf, the necessary energy to service Powerex's remaining sales. Powerex claims that netting across the entire time period is appropriate because over that period its purchases exceeded its electricity sales (*i.e.*, it experienced a surplus), and, thus, it did not need to make affiliate purchases.

53. The California Parties contend that Powerex has not included all of BC Hydro's excess power above native load. They argue that Powerex's calculations include two computational errors that understate the actual amount of BC Hydro power that Powerex must include in its cost filing: (1) Powerex's failure to limit the calculation to short-term transactions and (2) Powerex's use of a netting approach. According to the California Parties, when these errors are corrected, Powerex's cost filing is reduced to zero.

54. The California Parties state that the August 8 Order specifically limited the types of purchases that a marketer could include in its average cost portfolio to short-term purchases (defined as transactions of less than one month in term). They argue that, contrary to this limitation, Powerex has included both medium-term (balance of the month to three years) and long-term purchases (greater than three years) in its determination of BC Hydro's excess power above native load.[72]

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[70] *Id*. at P 277.

[71] *Id*. at P 278.

[72] *See* Berry Testimony at 6:14-19.

55. Finally, the California Parties contend that Powerex's use of a netting approach is inconsistent with the Commission's prior orders. Specifically, they argue that Powerex has improperly netted affiliate purchases with affiliate sales to determine the quantity of affiliate purchases to include in its purchase portfolio. The California Parties state that, in the August 8 Order, the Commission rejected the netting of sales and purchases when they could not be matched.[73]

56. Powerex responds that it is not appropriate to limit its calculation to short-term transactions because BC Hydro's generation relative to it load obligations is based on all of Powerex's sales and purchase commitments, regardless of how far in advance those commitments were executed. It adds that, exclusion of transactions of one month or longer, would yield an incomplete picture of the extent to which Powerex required BC Hydro generation to deliver on its obligations. Powerex also argues that it is appropriate to net transactions because, to the extent that BC Hydro produces power in excess of its own load obligations, it does so due to the net position between all of Powerex's sales and all of Powerex's purchases.

57. Contrary to the assertions of the California Parties, we find that Powerex's netting of its sales and purchase transactions, both long-term and short-term, is appropriate. In the August 8 Order, the Commission determined that CAISO and PX purchases should not be netted with CAISO and PX sales, but rather must remain part of the resource stack to determine portfolio price.[74] Powerex's analysis is different than that circumstance. Powerex, in using a portfolio-type approach, explained that it was necessary to net long-term and short-term affiliate sales and purchases to obtain the level of affiliate transactions available for resale to the CAISO and/or PX. Because BC Hydro generated power for Powerex when Powerex did not have enough power to fulfill its sales obligations, the Commission finds that Powerex's netting of purchases and sales is a reasonable approach to ascertain the quantity of short-term affiliate purchases to include in Powerex's average cost portfolio.

58. Also, because BC Hydro's generation relative to its load obligations was based upon all of Powerex's sales and purchase commitments regardless of how far in advance those commitments were executed, we believe it is reasonable for Powerex to account for both long-term and short-term transactions in its netting methodology. The netting of long-term and short-term purchases and sales produces a net number that is equivalent to short-term purchases from BC Hydro and thus should be included in Powerex's portfolio.

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[73] *Id*. at 6:24-7:2.

[74] *See* August 8 Order, 112 FERC ¶ 61,176 at P 89.

59. However, we find it illogical that Powerex has netted its surplus purchases with short-term purchases over the entire October 2, 2000 to January 16, 2001 time period. We find that Powerex's argument that, during a period of surplus, purchases reflect inputs to BC Hydro (and thus no affiliate purchases) does not negate the fact that at other times Powerex did purchase from BC Hydro for resale. Therefore, we find that Powerex should factor in the amount of the power that was exported from the BC Hydro system from October 2, 2000 through December 31, 2000 (*i.e.*, 239 GWh).[75] We believe that revising inputs based upon the two discrete time periods will result in a more accurate cost input calculation. Powerex would be able to artificially exclude affiliate purchases in its calculations if it were allowed to net surpluses in one period with shortages (*i.e.*, sales to BC Hydro). Accordingly, we direct Powerex to make this modification.

(2) Rates on File with the BCUC

60. Powerex states that it has included the BC Hydro rate schedule that was on file with the BCUC at the time the transactions occurred. According to Powerex, it was a bundled rate schedule under which customers that connected directly to the high-voltage (60 kV and higher) transmission system took service from the BC Hydro system. The charge in the BC Hydro rate schedule is a two part rate consisting of a demand charge of $ 4.411/kVa per month and an energy charge of $ 0.02599/kWh. Powerex states that, at a one-hundred percent load factor and a typical power factor of ninety-five percent, the delivered price of energy under this rate schedule would have been $32.44/MWh Canadian dollars.[76] Powerex states that applying the average exchange rate between October 2, 2000 and December 31, 2000 results in a rate of $21.25/MWh in U.S. dollars.

61. The California Parties assert that these rates cannot be verified. They state that, while Powerex has stated that the rate provided was a bundled rate and provided a dollar per MWh rate, Powerex has only submitted a one-page tariff schedule with an unsigned *pro forma* service agreement. They contend that this documentation is insufficient to verify that Powerex is using the correct rate schedule. Powerex responds that it has complied with the Commission's directive to file the pertinent tariff sheet and that the California Parties' inability to verify this rate is irrelevant.

62. In the January 26 Order, the Commission determined that the costs that will be representative of Powerex's affiliate purchases will be limited to the BC Hydro rate on file with the BCUC and that Powerex is to submit the representative tariff sheet demonstrating that cost.[77] Powerex has submitted the requisite tariff sheets and attests in

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[75] *See* Wong Affidavit at P 19.

[76] *Id.* at P 20.

[77] January 26 Order, 114 FERC ¶ 61,070 at P 278.

its filing that this BC Hydro rate schedule was effective during the Refund Period. We therefore find that Powerex has complied with the Commission's directive. Consistent with similar determinations in the January 26 Order,[78] we find that the BC Hydro tariff sheet is an acceptable demonstration of the cost of the BC Hydro system. Since the Commission has determined that the limit of Powerex's affiliate purchases will be that rate,[79] it is not necessary for Powerex to have had a service agreement with BC Hydro.

63. We accept the energy component of the BC Hydro tariff sheet but reject the kVa component. While Powerex has complied in providing the BC Hydro tariff sheet, we will only allow Powerex to use the energy charge of $.02599/kWh because Powerex's calculations from the tariff rates are erroneous. Powerex has made several assumptions, including a 95 percent power factor and a 100 percent load factor to calculate its rate of $0.03244/kWh. We find that Powerex's assumptions cannot be verified and result in an incorrect calculation with a different purchase cost than it demonstrates. Therefore, since the basic assumptions necessary to calculate Powerex's costs, including the power factor, cannot be validated, we reject Powerex's use of the kVa component of the BC Hydro two-part tariff rate. We find that Powerex must value its affiliate purchases at $0.01702/kWh, based on an average exchange rate of $0.655 Canadian to U.S. dollar.[80] Accordingly, we direct Powerex to make this modification.

c. Inclusion of Multi-Day Sales

64. Powerex states that the average portfolio purchase cost calculation cannot be finalized because the final settlement data from the CAISO and PX are still pending. Powerex states that, after this data is received and the average portfolio purchase cost has been recalculated, it will submit to the CAISO its revised cost offset filing, including, among other things, CAISO multi-day sales transactions.

65. The California Parties argue that Powerex should have included revenues from its multi-day transactions in its compliance filing. They challenge Powerex's suggestion that it has not performed these calculations because it has not received relevant CAISO settlement data. They argue that Powerex could have used the final revenue data for multi-day sales posted on the CAISO website and the final MMCPs published by the CAISO to comply with this directive. The California Parties contend that Powerex's

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[78] *See Id*. at P 11 and 71 (determining that actual tariff sheets are allowable to support costs).

[79] *Id.* at P 278.

[80] This amount is the $0.02599 energy charge component times $0.655. The $0.655 U.S. dollar to Canadian Dollar amount was derived from Powerex's rate calculations.

failure to include these revenues due to the lack of final settlement data from the CAISO is not adequate justification for not complying with the January 26 Order. Powerex responds that the Commission did not require it to submit the multi-day sales transactions in its compliance filing.

66. Contrary to the California Parties' argument, in the January 26 Order, the Commission only required Powerex to make a compliance filing with revised cost inputs, as opposed to revenue inputs.[81] Since the multi-day sales are revenue inputs, Powerex did not need to include them in its compliance filing. Instead, the Commission directed Powerex to include them, among other things, in its final cost offset to the CAISO.[82] Accordingly, we reject the California Parties' arguments and continue to direct Powerex to incorporate the final CAISO and PX data in its cost offset submittal to the CAISO.

d. Removal of Uninstructed Energy Purchases, Reconciling Errors and Reflecting Final Settlement Data

67. Powerex states that it has removed uninstructed energy purchase costs from its average portfolio purchase cost calculation in this compliance filing. With respect to the Commission's directive to reflect the CAISO and/or PX final settlement data for all revenues, Powerex states that, on February 16, 2006 and February 28, 2006, it received the final settlement data from the CAISO and PX, respectively. Powerex also states that, in its final cost offset submission to the CAISO, it will reconcile errors in revenues shown by Commission staff calculations.

68. We find that Powerex has properly removed its uninstructed energy purchase costs from its average portfolio purchase cost calculation. Furthermore, consistent with the January 26 Order, we direct Powerex to include the final settlement data from the CAISO and PX and reconcile the noted errors in revenue in the final cost offset it will submit to the CAISO.

e. Motion to Lodge

69. The California Parties seek to lodge the cost recovery submission that Powerex submitted to the CAISO on March 15, 2006. Through this motion to lodge, they seek to put before the Commission for its review a submission to the CAISO that the

[81] *See Id*. at P 280.

[82] *See Id*. at P 161 and 280.

Commission chose not to review.[83] In essence, they object to the Commission's failure in the January 26 Order to adopt a process for review of Powerex's submission to the CAISO to assure that the changes required in the January 26 Order were made correctly. Consequently, they seek to lodge Powerex's CAISO submission here to obtain the review not provided in the January 26 Order.

70. We find that the California Parties' motion to lodge is outside the scope of this compliance filing proceeding. It is in essence a challenge to the Commission's decision in the January 26 Order to allow Powerex to make a submission to the CAISO without prior Commission review. It is not a challenge to the contents of the compliance filings here. The California Parties have raised this issue in their request for rehearing of the January 26 Order and that is the appropriate venue to raise this issue. Accordingly, we deny the motion to lodge in this proceeding.

4. Sempra

71. In the January 26 Order, the Commission accepted Sempra's cost filing subject to modifications. The Commission directed Sempra to make several revisions: (1) remove affiliate purchases that utilized market indices or other market pricing;[84] (2) include multi-day sales;[85] (3) re-price matched City of Burbank (Burbank) transactions at MMCP and include them in either its average portfolio or matched calculations (not both);[86] (4) remove costs associated with sales of ancillary services;[87] (5) remove Show Cause settlement revenue offset;[88] (6) remove uninstructed energy purchase costs;[89] (7) remove

[83] If the Commission makes the submission part of the record, the California Parties request that the Commission summarily reject both of Powerex's claimed cost recovery offsets in that submission. The California Parties note that they contemporaneously filed a protest and comments to seller's cost filing submission to the CAISO, addressing the Commission's failure to adopt a process for review of the sellers' submissions to the CAISO to assure that the required changes have been made correctly.

[84] *Id*. at P 95.

[85] *Id*. at P 355.

[86] *Id*. at P 358-59.

[87] *Id*. at P 359.

[88] *Id*. at P 360.

[89] *Id*. at P 355.

return on investment;[90] (8) remove congestion net revenue;[91] and (9) reflect CAISO and/or PX final settlement data for all revenues, including all manual adjustments.[92]

Removal of Affiliate Purchases

72. In the January 26 Order, the Commission directed Sempra to revise its matched and average portfolio costs to eliminate all affiliate purchases that utilized market indices or other market pricing or resubmit to the Commission a revised average purchased power costs valuing affiliate transactions at actual production costs.[93]

73. Sempra states that it has revised its summary template to eliminate purchases from entities that are Sempra's affiliates, including El Dorado Energy, LLC (El Dorado); Sempra Generation; and Sempra Energy Solutions. Sempra states that it has removed any such purchases that it originally included as matched transactions calculations or that were included in its average energy purchase cost.

74. Sempra explains that to remove certain transactions it used average daily prices to create an average hourly price. Sempra contends that, in a total of 12 hours over 8 different days, the elimination of purchases from Sempra affiliates resulted in the elimination of all of Sempra's purchases in each of those 12 hours, rendering it impossible to calculate an hourly average energy purchase cost for those intervals. Therefore, for these 12 hours, Sempra has calculated a daily average energy purchase cost based on its purchases for the particular day in which each hour occurred. Sempra then calculated the cost associated with Sempra's sales in those hours by multiplying the daily average energy purchase cost by the quantity of energy sold in that hour.

75. The California Parties argue that Sempra's compliance filing includes calculation errors that result in an overstatement of Sempra's cost recovery refund offset. The California Parties contend that Sempra has ignored the Commission's directive to value purchases from affiliates at marginal production cost. In particular, the California Parties claim that Sempra has made an erroneous adjustment by removing all purchases from El Dorado, a Sempra affiliate. The California Parties argue that the exclusion of all purchases from El Dorado is nonsensical because, without them, Sempra's portfolio of

[90] *Id*.

[91] *Id*.

[92] *Id*. at App. B.

[93] *Id*. at P 95.

purchases would be insufficient to cover Sempra's sales to the PX and CAISO. The California Parties further argue that it is inappropriate for Sempra to base its affiliate costs on its other, third-party purchases.

76. Sempra responds that the California Parties' position on the affiliate pricing issue is an attempt to re-argue positions rejected by the Commission in the January 26 Order. Sempra states that the Commission's directive on affiliate purchases was clear: to revise its matched and average portfolio costs to eliminate all affiliate purchases that utilized market indexes or other market pricing or resubmit to the Commission a revised average purchased power cost valuing affiliate transactions at actual production costs. Sempra argues that, through this directive, the Commission authorized the removal of affiliate purchases and did not mandate the computation of affiliate production costs.

77. We disagree with Sempra's contention that its methodology constitutes removal of affiliate transactions and thus comports with the directives of the January 26 Order. While the Commission gave Sempra the option of either revaluing its affiliate purchases at the actual cost of production or removing the transactions altogether, Sempra has failed to follow either approach in its compliance filing. By removing its affiliate costs without removing the associated revenues, Sempra's calculations essentially create an arbitrary proxy price at which to value affiliate purchases rather than exclude the entire transaction. Furthermore, we find that the cost demonstration in the compliance filing constitutes disallowed opportunity pricing (*i.e.*, valuing affiliate transactions at prices other than the cost of production presents a value of the energy that these sellers could have otherwise received if they sold that energy in the market).[94]

78. Sempra has not only failed to re-price its affiliate purchases to actual costs of production but also has failed to explain why such a value could not be determined. Sempra has not provided any evidence, either in its original cost offset filing or in its compliance filing, explaining why it lacks information regarding the operating costs of its affiliate generators. Furthermore, Sempra has provided no evidence in its compliance filing to justify the assumption that its average price proxy is equivalent to its affiliate generators' actual costs of production. Therefore, we reject Sempra's re-priced affiliate purchase costs because Sempra has failed to comply with the directives in the January 26 Order.

79. Because none of Sempra's affiliate purchases were matched directly to the associated revenue, simply disallowing those costs is problematic. Sempra's affiliate purchases constitute a significant factor of its average cost portfolio and cannot be extrapolated. Furthermore, the inclusion of Sempra's non-compliant affiliate purchases

[94] *See* August 8 Order, 112 FERC ¶ 61,176 at P 72.

in the average portfolio cost skews the calculation artificially upward and inflates Sempra's actual costs and resulting cost offset claim. Therefore, we reject Sempra's compliance filing.

80. In addition, Sempra has failed to comply with the prior Commission directives on what evidence was necessary to support refund cost offsets. Sempra has been provided sufficient opportunity to make substantial showings. Therefore, because Sempra has failed to support its affiliate purchase costs and because these costs are an integral part of its average cost portfolio, we reject Sempra's entire proposed cost offset as unsupported. This determination is consistent with the January 26 Order, in which the Commission rejected the filings of Merrill Lynch Capital Services, Inc. and Allegheny Energy Supply Company LLC for failure to support average cost portfolios with sufficient documentation.

5. TransAlta

81. In the January 26 Order, the Commission accepted TransAlta's cost filing subject to modifications. The Commission directed TransAlta to make several revisions: (1) remove affiliate purchases that utilized market indices or other market pricing;[95] (2) remove all control area fees;[96] (3) remove PX chargeback costs; (4) adjust revenues as agreed to in TransAlta's reply comments;[97] (5) reflect CAISO and/or PX final settlement data for all revenues, including all manual adjustments;[98] and (6) reflect final APX settlement data.[99]

Removal of Affiliate Purchases

82. In the January 26 Order, the Commission directed TransAlta to revise its matched and average portfolio costs to eliminate all affiliate purchases that utilized market indexes or other market pricing or resubmit to the Commission a revised average purchased power costs valuing affiliate transactions at actual production costs.[100]

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[95] January 26 Order, 114 FERC ¶ 61,070 at P 95 and 383.

[96] *Id*. at P 384.

[97] *Id*. at App. B.

[98] *Id*.

[99] *Id*.

[100] *Citing Id*. at P 95.

83. TransAlta states that it applied a three-pronged approach to reprice the power purchases from its affiliate, TransAlta Centralia Generation LLC (Centralia). First, it replaced the affiliate transaction cost for a given hour with the weighted average cost of unmatched purchases for non-affiliates in a given hour. If unmatched purchases were not available in a particular hour, TransAlta then used the weighted average cost of matched transactions in that hour from non-affiliate transactions. Finally, if neither of these options were available, TransAlta used the weighted average cost of energy acquired from all non-affiliate purchases recorded for that given hour in all WECC trading books.

84. The California Parties argue that, contrary to the January 26 Order,[101] TransAlta has failed to revalue its affiliate purchases at the cost of production. The California Parties claim that using an averaging technique to value affiliate costs is a proxy for the market-based pricing that TransAlta was directed to eliminate. The California Parties argue that the supplier must demonstrate the actual production or purchase costs of the corporate entity – not merely the supplier. According to the California Parties, for TransAlta, the actual incremental cost to the corporate entity is its affiliate's generating costs.

85. TransAlta responds that the Commission did not state that TransAlta had no alternative but to recalculate all purchases from its affiliate at the affiliate's cost of production and to use that cost wherever TransAlta had reported supply used from its affiliate, either specifically or as part of an average cost, as the California Parties suggest. TransAlta argues that the California Parties ignore that TransAlta was able to identify purchases from non-affiliates in every hour that TransAlta included data on the purchase price under the contract that TransAlta had with its affiliate. TransAlta underscores that these prices were determined in arm's-length transactions. TransAlta argues that, since the Commission established in the August 8 Order that the price negotiated with third parties was the basis for the cost recovery filings, it was appropriate for TransAlta to conclude that the Commission had given it the choice to use such prices in lieu of the rejected, but erroneously characterized, "index" prices that the Commission assumed TransAlta had used in its original cost filing. TransAlta states that its method for revaluing affiliate transactions is similar to the methods used by Powerex and PPL Montana, LLC (PPL). It adds that the Commission has not adopted a policy that all affiliate purchases must be priced at the incremental costs of production because the Commission approved the Powerex and PPL cost filings on a different basis.

86. The California Parties do not agree that the Commission's approval of affiliate transactions in the Powerex and PPL cost filings justifies TransAlta's failure to price affiliate transactions at actual production costs. They argue that TransAlta's proposal to

[101] They note that the Commission stated that "the relevant marginal costs are those that would have been avoided had no sales been made into the CAISO and PX markets." *Quoting Id*. at P 96.

use a non-cost-based, market-average approach for pricing production from its affiliated coal-fired generator cannot be squared with the Powerex and PPL rulings. They state that, with Powerex, the Commission dealt with costs of affiliate hydro-electric energy imported to the United States and required the costs to be priced at a rate on file with the BCUC.[102] They state that, with PPL, the Commission approved PPL's calculation of actual production costs.[103]

87. Contrary to TransAlta's arguments, the Commission did not authorize filers with affiliate transactions to utilize any value other than the actual cost of production of an affiliate generator. In fact, the Commission rejected such approaches in the January 26 Order, stating that "allowing cost recovery for affiliate purchases at … any rate above the actual cost … would unjustly diminish the value of refunds."[104] If we were to allow sellers to pass through average cost calculations to value purchases from affiliate generators, we would be permitting the intra-corporate sheltering that the January 26 Order sought to prevent. While the market value of power purchases may significantly vary from hour to hour, the cost of generating power does not. Therefore, it would be unreasonable for the Commission to accept TransAlta's unsubstantiated claims that hourly average costs of purchased power bear a relation to the actual costs faced by an affiliate generating unit.

88. TransAlta's assertion that, in the January 26 Order, the Commission allowed it to use its average portfolio costs in the place of actual costs of production is also incorrect. In the January 26 Order, the Commission unambiguously directed all affiliate transactions to be valued at actual production costs.[105] A complete reading of the sections of the order that address this issue indicates that the Commission required any seller wishing to include affiliate transactions to first value those transactions at the cost of production and then, to the extent necessary, to adjust its average portfolio cost to reflect the corrected value.[106] Furthermore, we find that TransAlta's comparison of its own filing with those of PPL and Powerex is off point because, unlike TransAlta, PPL and

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[102] *Citing Id*. at P 278.

[103] *Citing Id*. at P 295.

[104] *Id*. at P 94.

[105] *Id*. at P 383 (*citing* P 95). We note that the discussion of this affiliate issue in the Affiliates Section and the TransAlta Section of the January 26 Order are to be read together, as indicated by the reference in paragraph 383 of the TransAlta Section back to the discussion in paragraph 95 of the Affiliates Section.

[106] *Id*.

Powerex demonstrated either their actual costs of production or provided an acceptable approximation of those costs.[107] Thus, the Commission finds that TransAlta's use of an averaging approach to estimate a proxy for affiliate costs is erroneous. TransAlta has not provided any evidence that its averaging technique approximates the marginal cost of affiliate purchases made for sale into the CAISO and PX markets during the Refund Period. Furthermore, it has not provided any explanation for its failure to demonstrate the actual production costs faced by its affiliate, Centralia.

89. As with Sempra, a significant number of TransAlta's affiliate purchases were factored into its average cost portfolio, complicating the rejection of that category of purchases alone. Furthermore, as discussed with regard to Sempra, the inclusion of non-compliant affiliate purchases in TransAlta's average portfolio cost skew the calculations resulting in an artificial inflation of TransAlta's actual costs and resulting cost offset claim. As with Sempra, TransAlta has been provided sufficient opportunities to support its affiliate purchases claims. Therefore, because TransAlta has failed to support its affiliate purchase costs and because the cumulative impact of these purchases cannot be extrapolated from its average cost portfolio, we reject TransAlta's compliance filing and reject its proposed cost offset as unsupported.

The Commission orders:

(A) Avista's compliance filing is hereby accepted, as discussed in the body of this order.

(B) Portland General's and Powerex's compliance filing are hereby conditionally accepted, subject to modification, as discussed in the body of this order.

(C) Avista, Portland General and Powerex are hereby directed to submit final cost offsets, incorporating the directives discussed in the body of this order, with the CAISO within 15 days of the date of this order, as discussed in the body of this order.

[107] In the case of PPL, the Commission determined that PPL had appropriately demonstrated its actual costs of generating power. In the case of Powerex, it submitted its rate on file with the BCUC which, as we have determined in this order, represents a reasonable demonstration of Powerex's cost of obtaining power from its BC Hydro plant.

(D) Sempra's and TransAlta's compliance filings and proposed cost offsets are hereby rejected, as discussed in the body of this order.

By the Commission. Commissioner Spitzer not participating.

(S E A L)

Magalie R. Salas,
Secretary.